TECHNICAL REVIEW DOCUMENT
For
RENEWAL of OPERATING PERMIT 96OPAD136

Public Service Company – Arapahoe Station
Denver County
Source ID 0310008

Prepared by Jacqueline Joyce
December 2008
Revised February and March 2009

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit proposed for this site. The original Operating Permit was issued December 1, 2001. The expiration date for the permit was December 1, 2006. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted November 18, 2005, comments on the draft permit and technical review document submitted on March 13, 2009, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility is an electric generating facility. Electricity is produced through two coal-fired boilers. Although coal is the primary fuel burned, these units use natural gas as a back-up fuel. Unit No. 3 is a 48 MW boiler that is equipped with a baghouse to control particulate matter emissions. A dry sodium injection system was recently installed on Unit 3 to control SO_2 emissions. The dry sodium injection system became operational in January 1, 2003. Unit No. 4 is a 118 MW boiler that is equipped with a baghouse, low NO_X burners with overfire air to control NO_X emissions and a dry sodium injection system to control SO_2 emissions. Unit No. 4 was also the subject of a urea injection study which has been completed. Although the study is complete the equipment has not been removed though the equipment is out of service. Units 3 and 4 share a stack. Other emission sources at Arapahoe include fugitive emissions from coal handling and storage and from traffic on paved and/or unpaved roads. Note that a permit was issued for an upgrade to the coal handling system in October of 1999 and the new coal unloading facility commenced operation in June 2000. The new rail spur and coal unloading operation is included in this permit. Finally, Arapahoe Station has point source emissions from one (1) ash silo, two (2) coal crushers (note that only one crusher can operate at a time), the coal conveying system, three (3) sodium reagent silos, three (3) cooling water towers and several Safety-Kleen cold cleaners that have applicable requirements and therefore have been included in the Operating Permit. In addition, Public Service Company (PSCo) entered into a Voluntary Emissions Reduction Agreement with the Division. The provisions of the agreement became effective on January 1, 2003 and the appropriate provisions of that agreement have been included in this permit. As part of this agreement, Units 1 and 2 were retired effective January 1, 2003.

The PSCo's Arapahoe Generating Station is co-located with SWG Colorado's Arapahoe Combustion Turbine Facility. Since the two facilities are located on contiguous and adjacent property, belong to the same industrial grouping (first two digits of the SIC code are the same) and are under common control (PSCo exerts control over SWG Colorado via a power purchase agreement), they are considered a single stationary source for purposes of major stationary source new source review and Title V operating permit applicability. A separate Title V operating permit was issued for SWG Colorado's Arapahoe Combustion Turbine Facility (01OPDE237).

The facility is located at 2601 South Platte River Drive in Denver County, within the Denver metro area. The Denver metro area is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide. Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver metro area is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagle's Nest National Wilderness Area, both Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	Pb[1]	HAPS
PSCo – Arapahoe Station (96OPDE136)								
Boiler 3 (Unit 3)	330.6	304.15	3,636.36	2,644.82	272.26	17.83	0.08	See Page 20
Boiler 4 (Unit 4)	748.72	688.82	8,235.89	4,492.30	616.59	40.37	0.18	
Ash Handling (point source - Silo)	6.7	6.7						
Coal Handling (point source – rail car unloading station and conveyor)	6.1	2.9						
Coal Handling (point source – from unloading to units)	0.90	0.42						
Coal Handling (fugitive)	152.3	35.1						
Sodium Reagent Silos	0.015	0.015						
Cooling Towers	1.82	1.82				2.19		
Haul Roads (fugitive)	19.4	8.0						
Total PSCo Emissions	**1,266.55**	**1,047.93**	**11,872.52**	**7,137.12**	**888.85**	**60.39**	**0.26**	**55.49**
SWG Colorado LLC – Arapahoe Combustion Turbines (01OPDE237)								
Turbines, duct burners, heaters and engines	14.9	14.9	1.2	39.0	90.8	7.6		See Page 20
Total SWG Emissions	**14.9**	**14.9**	**1.2**	**39.0**	**90.8**	**7.6**		**5.65**
Total FACILITY Emissions	**1,281.45**	**1,062.83**	**11,873.72**	**7,176.12**	**979.65**	**67.99**	**0.26**	**61.14**

[1]Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

Potential to emit used in the above table are based on the following information:

Criteria Pollutants

Potential to emit for the ash silo (ash handling – pt source), sodium reagent silos and the new rail coal unloading station and associated conveyors (coal handling pt source) are based on permitted emissions.

Potential to emit for NO_X, SO_2 and PM from boilers 3 and 4 are based on emission limitations included in the permit (Reg 1 for SO_2, PM and NO_X, for boiler 4, (1.1 lb/mmBtu, 0.1 lb/mmBtu and 0.6 lb/mmBtu, respectively) and the Acid Rain limits for NO_X for boiler 3 (0.80 lb/mmBtu)), the design heat input rate and 8760 hours per year of operation. PM_{10} emissions from boilers 3 and 4 are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6). VOC and CO emissions from boilers 3 and 4 are based on emissions from the worst-case fuel. Emissions from VOC and CO were estimated using AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19 for coal and Section 1.4, dated 3/98, Tables 1.4-1 and 1.4-2 for natural gas) and the maximum fuel consumption rate. The maximum coal consumption rate is based on the design heat input rate, the heat content of the coal from the APEN submitted on April 30, 2008 and 8760 hours per year of operation. The maximum natural gas consumption rate is based on the design heat input rate, a natural gas heat content of 1020 Btu/scf (per AP-42) and 8760 hours per year of operation.

Potential to emit from the cooling towers is based on the estimates provided in the original Title V permit application, which was submitted on November 15, 1996.

Potential to emit from fugitive emissions from coal handling and the haul roads and the coal handling system (pt source – from unloading to units) is based on the estimates provided in the original Title V permit application, which was submitted on November 15, 1996. These estimates were ratcheted down to take into account the retirement of boilers 1 and 2, which occurred after the submittal of that application.

Potential to emit from the SWG Colorado Arapahoe Combustion Turbine Facility are based on permitted emissions. The emission limitations in the permit are facility wide limits.

Hazardous Air Pollutants (HAP)

The potential to emit table on page 3 provides total HAPs for each operating permit. The breakdown of HAP emissions by individual HAP and emission unit is provided on page 20 of this document. HAP emissions, as shown in the table on page 20, are based on the following information:

Potential to emit of HAPS were only determined for boilers 3 and 4 and the cooling towers. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

Metal HAP emissions from boilers 3 and 4 are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the maximum coal consumption rate. Mercury emissions from boilers 3 and 4 are based on the average projected mercury emissions that were used in the development of Colorado's Mercury Rule. HF and HCl emissions from boilers 3 and 4 are based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2007, 2006, 2005 and 2004 data) and the maximum coal consumption rate. These emission estimates take credit for the dry sodium injection system (according to the source, control efficiencies of 88.5 % for HCl and 72% for HF were assumed). Emissions of benzene, formaldehyde, hexane and toluene are based on AP-42 emission factors (Section 1.4, dated 3/98, Table 1.4-3) and the maximum natural gas consumption rate.

HAP emissions from the cooling towers are based on the design circulation rate, 8760 hours per year of operation and the chloroform emission factor specified in the Title V permit (based on a letter from Wayne C. Micheletti to Ed Lasnik, dated November 11, 1992).

HAP emissions from SWG Arapahoe turbines, duct burners, heaters and engines are based on AP-42 emission factors, design rate and 8760 hours per year of operation since there are no fuel consumption limits specified in the SWG Arapahoe permit. HAP emissions from the SWG Arapahoe cooling tower are based on the same chloroform emission factor used for the PSCo cooling towers.

Note that actual emissions are typically less than potential emissions and actual emissions from the PSCo sources are shown on page 21 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in the document under Section III – Discussion of Modifications Made, under "Source Requested Modifications".

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Arapahoe Station was not a major source for HAPS. However, the Division has determined that the facility is a major source for HAP emissions with equipment under the source category for reciprocating internal combustion engines.

Since the EPA has signed off on final rules for all of the source categories, which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp.; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There is one diesel-fired engine included in Section II of the current permit and one diesel fired engine included in the insignificant activity list. One of these, the emergency generator, which is included in the insignificant activity list, is greater than 500 hp and the other (drives an air compressor) is less than 500 hp. Since the emergency generator is an existing compression ignition engine, it does not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements as specified in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3).

In addition, revisions were made to the RICE MACT to address engines $\leq$ 500 hp at major sources and all size engines at area sources. These revisions were published in the Federal Register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines $\leq$ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. The air compressor engine, which is included in Section II of the current permit is considered existing and therefore is not subject to the MACT. However, as the source indicated in their renewal application (submitted on November 18, 2005) the air compressor engine has been removed from service and is no longer on site.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. It is not clear whether 112(j) applications would be required for emission units, such as the small heaters used for comfort heat, which were excluded from the Boiler MACT. Therefore, the Division has not included a requirement in the permit to submit a 112(j) application. If the Division considers that in the future, a 112(j) application will be required for these small units the source will be notified.

Gasoline Distribution MACTs

A 500 gallon aboveground gasoline tank is included in the insignificant activity list (listed as an insignificant activity because emissions are less than the APEN de minimis level per Reg 3, Part C, Section II.E.3.a). There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the Federal Register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the Federal Register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

Note that since this tank is less than 550 gallons it is not subject to the Requirements in Colorado Regulation No. 7, Section VI.B.3.b.

Federal Clean Air Mercury Rule Requirements

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule (primarily for monitoring and reporting requirements), there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect. In addition, on November 20, 2008, the Colorado Air Quality Control Commissions (AQCC) adopted into Reg 6, Part B, Section VIII, the monitoring, recordkeeping and reporting requirements in the vacated CAMR rule. The revisions to Reg 6, Part B take effect on December 30, 2008.

To that end, as an existing mercury budget unit boilers 3 and 4 are required to comply with either of the following standards on a 12-month rolling average basis beginning January 1, 2014 (Colorado Regulation No. 6, Part B, Section VIII.C.1.b):

0.0174 lb/GWh OR 80 percent capture of inlet mercury

The boilers would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

It should be noted that if either boiler qualifies as a low emitter (actual mercury emissions of no more than 29 lbs/yr), the mercury standards indicated above do not apply.

Since the mercury limitations do not apply until 2014 and the permit application is not due until 18 months prior to commencing construction on the mercury control equipment

(Colorado Regulation No. 6, Part B, Section VIII.D.2) the renewal permit does not include the state-only mercury requirements.

Regional Haze Requirements

One element of the Regional Haze program is the requirement for certain stationary sources to install Best Available Retrofit Technology (BART) to reduce emissions of visibility impairing pollutants. BART is required for certain stationary sources which were not in operation as of August 7, 1962 and which were in existence as of August 7, 1977. Both boilers at this facility were operating prior to August 7, 1962; therefore, a BART analysis was not required for the units at this facility. At this time, Arapahoe station does not have any requirements under the Division's Regional Haze program.

III. Discussion of Modifications Made

Source Requested Modifications

The source requested the following changes in their November 18, 2005 renewal application.

Section I, Condition 5 (Compliance Assurance Monitoring (CAM))

The source indicated that this condition needed to be revised to address the CAM requirements for this facility. The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level. There are several emission points at the facility that could potentially be subject to the CAM requirements. The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

Emission sources with no emission limitations

The source identified the following activities as units with no emission limitations and therefore not subject to the CAM requirements: the cold cleaner solvent vat, the cooling tower and fugitive emissions from coal handling and storage and traffic on paved and unpaved roads.

Emission sources with emission limitations

No control device

The diesel-fired air compressor is subject to Reg 1 SO_2 and annual emission limitations of NO_X and CO. However, the unit is not equipped with a control device, therefore, the CAM requirements do not apply to this unit. In addition, the source has indicated that the air compressor is no longer at the plant site.

Pre-control emissions below the major source level

The following emission units have pre-control emissions below the major source level and therefore are not subject to CAM.

Ash silo: PM and PM_{10} emissions were calculated for these emissions units using the uncontrolled emission factors specified in the permit and the permitted throughput rate and emissions were below the major source level for each activity. Note that for the ash silo total emissions from silo loading and the most conservative unloading option (open truck) were below the major source level.

Sodium Reagent silos: Permitted emissions from these emission units are based on grain loading specifications from the manufacturer and design rate for the blowers. Therefore estimating uncontrolled emissions are difficult. Based on the permitted emission rate, and assuming a control efficiency of 99.9 %, uncontrolled emissions from these units are below the major source level.

Railcar unloading station and associated conveyors: Permitted emissions from the rail car unloading station and associated conveyors are based on emission factors for transfer or drop points that rely on wind speed and the moisture content of the coal. Permitted emissions are based on a wind speed of 8.7 mph, which does not take credit for covered conveyors. Therefore, since permitted emissions do not take credit for controls, permitted emissions are uncontrolled emissions and are below the major source level.

Pre-control emissions above the major source level

The source identified both boilers as having pre-control emissions above the major source level. The boilers are both subject to PM, SO_2 and NO_X emission limitations. Controlled emissions of these pollutants exceed the major source level and these units use emission controls (baghouses for PM, dry sodium injection for SO_2 and low NO_X burners and over-fire air for NO_X (boiler 4 only)) to meet their emission limitations. Therefore, the boilers are potentially subject to the CAM requirements.

Both boilers are subject to SO_2 and NO_X emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Both boilers are subject to a short-term SO_2 emission limitations (3-hr rolling average) and annual SO_2 emission limitation for the Metro units (per a voluntary emissions reduction agreement). Boiler 4 is subject to a 30-day SO_2 limitation during certain parts of the year and an annual SO_2 percent reduction requirement, as well as a 30-day NO_X limitation. The current Title V permit requires that both boilers use continuous emission monitoring systems to demonstrate compliance with the SO_2 and NO_X emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

CAM does apply to boilers 3 and 4 with respect to the PM emission limitations. Note that although both boilers are subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division accepts the indicator range of 15% opacity for one minute or more and will include this in the permit.

The second indicator range of “a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time” is non-specific as to the time frame and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions specified in Subpart Da require that a baseline opacity level be set during a performance test and then requires monitoring of opacity emissions on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action. Note that as provided for in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iv), periods of startup, shutdown and malfunction may be excluded from the 24-hour average.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. Since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations, the opacity add-on will be based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

Pressure Differential

The source has indicated that an excursion would be “an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit’s normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%”. While the proposed language does not specifically define the pressure differential for the “unit’s normal specific operating load”, in their justification the source indicates that the normal pressure differential varies based on the operating load. While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred. In addition, as indicated in the CAM plan, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system). As discussed previously, the Division has revised the source’s CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da. The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 Federal Register, although changes to the monitoring requirements were published as final in the Federal Register on June 13, 2007. New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity. Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests. While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the PM limitations. Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The preventative maintenance that the source has proposed is a monthly review of historic minute opacity data and that based on this review, if warranted, repairs will be initiated to internal and/or external baghouse components. It is not clear what specifically the source would be looking for in the historic minute opacity data and what would trigger any repairs. The Division considers that preventative maintenance is important to the proper operation of the baghouse, therefore, the Division has revised the preventative maintenance indicator to require semi-annual internal inspections of the baghouse. This indicator has been included in other CAM plans for other PSCo facilities.

In general, the CAM plan has been included in Appendix H of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

Both boilers burn coal as their primary fuel; however, both units can operate on natural gas only as a back-up fuel. Although both units are equipped with baghouses, when burning natural gas, both boilers would be able to meet the PM emission limitation without the baghouse. Therefore, when the boilers burn only natural gas as fuel, CAM would not apply.

Section I, Condition 6 (page 4)

The source indicated that the Ingersol-Rand diesel-fired air compressor (emission unit E001 has been removed from service and is no longer at the plant site. The source requested that the emission source be from the table in Condition 6 and from Section II, Condition 4 of the permit. The changes have been made as requested.

Section II, Condition 9.1 (page 23)

The source requested that the references to the Public Service Company Policy Manual regarding work practices for using solvent cold cleaners should be changed to “applicable Arapahoe Station operating guidelines”. The changes have been made as requested.

Section II, Condition 10.1 (page 23)

The source requested that the operation and maintenance requirements for the boiler be linked to the CAM plan and suggest that the language in Condition 10.1 be revised to reference the CAM plan.

The Division has added the CAM requirements as “new” conditions 1.13 and 17. The Division removed the language in Condition 10.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

Section II, Condition 16.1.4 (page 29)

The source indicated that the “startup period” of the voluntary agreement has passed and that this requirement should be removed from the permit. The change has been made as requested. In addition, the Division removed Condition 16.2.4, which also relates to the “startup period”.

In their comments on the draft permit and technical review document (received on March 13, 2009), the source requested the following changes to the permit:

Section II, Condition 7.1.1.2 in Current Permit (Condition 6.1.1.2 in draft renewal permit)

In their comments on the draft permit, the source indicated that the description of open truck loading was not correct and requested that the description be revised. The change has been made as requested.

Appendix A – Insignificant Activity list

In their comments on the draft permit, the source requested that the following changes be made to the insignificant activity:

- Under “units with emissions less than APEN de minimis (Reg 3, Part C.II.E.3.a)” the sulfuric acid storage tank size should be 8,000 gal, not 6,000 gal.

- Under “lubricating oil storage tanks < 40,000 gal (Reg 3, Part C.II.E.3.aaa)” add a 500 gal above ground turbine lube oil tank.

- Under “storage tanks < 400,000 gal (Reg 3, Part C.II.E.3.fff)” remove the diesel fuel tank for refueling heavy vehicles.

The changes have been made as requested.

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Arapahoe Station Operating Permit with the source’s requested modifications. These changes are as follows:

General

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

- Various permit conditions were re-numbered due to the removal of Section II, Condition 4.

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- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Changed the responsible official.

Section I - General Activities and Summary

- Revised Condition 1.1 to indicate that the SWG Colorado Arapahoe Combustion Turbine Facility is co-located and that the two facilities (SWG and PSCo) are considered a single source.

- Revised Condition 1.1 to appropriately address the attainment status of the area in which the facility is located.

- In Condition 1.4, the phrase "last paragraph" was added after Section V, condition 3.g to indicate which part is state-only enforceable. In addition, Section V, condition 3.d was added as a state only condition in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP.

- Made minor revisions to the language in Condition 3 (prevention of significant deterioration) to be more consistent with other permits. In addition, revised this condition to address the attainment status of the area in which the facility is located.

- Added a column to the Table in Condition 6.1 for the startup date of the equipment.

Section II.1 – Boilers 3 and 4 (Units 3 and 4), Coal Firing

- Added "Unit 3" and "Unit 4" to the table header to more clearly identify the units.

- References to fuel usage or fuel sampling were replaced with coal usage or coal sampling.

- Revised the language in Condition 1.1.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Removed the last sentence in Condition 1.2, regarding the ash content of the coal. Since the ash content of the coal is not used in the emission calculations in Condition 1.2, this sentence is not necessary.

- Replaced the word “demonstrated” with “monitored” in Condition 1.3.1.

- Removed the last sentence from Condition 1.12. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

Section II.2 – Boilers 3 and 4 (Units 3 and 4), Natural Gas Firing

- Added “Unit 3” and “Unit 4” to the table header to more clearly identify the units.

- Based on EPA’s response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Corrected the condition number in the references to annual fuel usage in Conditions 2.2 and 2.5. The correct condition number to reference is Condition 2.6.

- Removed the last sentence from Condition 2.10. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

Section II.3 –Boilers 3 and 4 (Units 3 and 4) , Combination Fired

- Added “Unit 3” and “Unit 4” to the table header to more clearly identify the units.

Section II.9 - Cold Cleaner Solvent Vat

- Added the following note under the table “Note that this emission unit is exempt from the APEN reporting requirements in Regulation No.3, Part A and the construction permit requirements in Regulation No. 3, Part B.”

Section II.10 – Particulate Matter Emission Periodic Monitoring Requirements

- Revised the stack testing language in Condition 10.2 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.11 – Continuous Emissions Monitoring System Requirements

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 11.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 11.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Based on citizen comments on another Title V permit, Condition 11.4.3 (monitoring opacity when the COM is down) was removed from the permit.

- Replaced the phrase "concerning upset conditions and breakdowns" with "concerning affirmative defense provisions for excess emissions during malfunctions" in Condition 11.5.5 to reflect revisions made to the Division's Common Provisions Regulation.

Section II.16 – Voluntary Emissions Reduction Agreement – State-only Requirements

Note that the Voluntary Emissions Reduction Agreement is currently a state-only enforceable requirement. However, upon approval of this agreement into the Visibility SIP, these provisions will become both state and federally enforceable.

- Removed the language in parentheses from Condition 16.1.1.3.

- Revised Condition 16.1.2 to replace "upset conditions" with "malfunction".

- Removed Condition 16.1.5 "Startup Problems" since this situation applies to the initial startup of the control technology, not to routine startups of the equipment.

- Revised Condition 16.1.6 to replace "upset conditions" with malfunction" and to remove "startup problems".

- Revised Condition 16.2.1.1 to replace “Upset Conditions” with “Malfunctions” and to remove the references to “Startup Problems”.

- Revised Condition 16.2.2 to replace “Upset Condition” with “Malfunctions”.

Section II.18 – Provisions for Retirement of Units 1 and 2

- The language in Conditions 17.3.2.4 and 17.3.2.6 was revised to more appropriately reflect the language in the underlying regulations.

Section III – Acid Rain Requirements

- Revised the Designated Representative.

- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal. Note that this section was revised to include both units on one table, rather than separate tables for each unit.

- Revised the NO_X limits to reflect the current NO_X averaging plan, which goes through 2009

- Minor changes were made to the standard requirements (Section 4), based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement in Section 4 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

- Removed the requirement to submit the annual reports and compliance certifications in Section 4. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the Federal Register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. Note that although the CAIR rule was vacated (July 2008), this revision was unrelated to the CAIR rule and it is expected that these changes will not be affected by the CAIR vacatur. Note that in December 2008, the vacatur of the CAIR rule was over-turned.

Section IV – Permit Shield

- The citation for the permit shield has been revised to reflect revisions and restructuring of Reg 3 and to remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(l) since they don’t address the permit shield.

- Corrected the table in Section 1 (Specific Non-Applicable Requirements) to reflect Boilers 3 and 4, rather than Boilers 1 and 2, which are retired.

- In Section 3 (Streamlined Conditions) some conditions were renumbered to reflect the removal of Section II, Condition 4 from the permit.

Section V – General Conditions

- The upset requirements in the Common Provisions Regulation (general condition 3.d) were revised December 15, 2006 (effective March 7, 2007) and the revisions were included in the permit. Note that these provisions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP).

- Removed the statement in Condition 3.g (affirmative defense provisions) addressing EPA approval and state-only applicability. The EPA has approved the affirmative defense provisions, with one exception and the exception, which is state-only enforceable is identified in Section I, Condition 1.4.

- Replaced the reference to "upset" in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with "malfunction".

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- Replaced the phrase "enhanced monitoring" with "compliance assurance monitoring" in General Condition No. 22.d.

Appendices

- Replaced Appendices B and C with the latest versions.

- Changed the mailing address for EPA in Appendix D. Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.

Arapahoe (PSCo and SWG) Total HAP Emissions

	HCl	HF	Mercury	Metals	Formaldehyde	Hexane	Acetaldehyde	BTEX	Chloroform	Total
Boiler 3	3.80	3.85	1.50E-02	2.57	0.24	5.83		1.78E-02	2.19	18.51
Boiler 4	8.60	8.72	2.99E-02	5.82	0.55	13.21		4.04E-02		36.97
Cooling Towers										
SWG Turbines					2.04E-00		1.15E-01	6.85E-01		2.84
SWG Heaters and Duct Burners				2.34E-03	8.35E-02	2.01E-00		6.13E-03		2.10
SWG Engines					1.09E-02		3.47E-03	1.72E-01		0.19
SWG Cooling Tower									5.17E-01	0.52
Total	12.39	12.57	4.49E-02	8.39	2.93	21.06	0.12	9.21E-01	2.71E-00	61.13
Total - SWG Emissions	0.00	0.00	0.00E+01	2.34E-03	2.13	2.01E-00	0.12	8.63E-01	5.17E-01	5.65
Total - PSCo Emissions	12.39	12.57	4.49E-02	8.39	0.79	19.05	0.00	5.82E-02	2.19E-00	55.49

HAP emission factors for Boilers 3 and 4 are based on emissions from worst case fuel.
HCl and HF emissions from Boilers 3 and 4 are based on emission factors used to report actual emissions on APENs and take credit for the dry sodium injection systems. According to the source control efficiencies of 88.5% for HCl and 72% for HF were used.

PSCo Arapahoe Actual Emissions (tons/yr)

Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Boiler 3	56.5	52	1,025.7	1,729.2	67.8	7.2	3.71
Boiler 4	110	101.2	1,936.7	1,250.3	141.9	15.4	8.26
Coal - fugitive	10.3	3.1					
Coal - pt source*	6.6	2					
Ash - pt source (silo)	2.3	2.3					
Haul Roads - fug	0.7	0.1					
sodium reagent silos	0.05	0.05					
cooling towers	1.5	1.5				1.3	1.3
cold cleaner solvent vats**							
Total	187.95	162.25	2,962.40	2,979.50	209.70	23.90	13.27
Total - Fugitive	11.00	3.20	0.00	0.00	0.00	0.00	0.00
Total - Point source	176.95	159.05	2,962.40	2,979.50	209.70	23.90	13.27

*includes both the permitted rail car unloading station and conveying from the pile to the units.
**the cold cleaner solvent vats are not subject to APEN reporting requirements, therefore, actual emissions are not shown.

Actual emissions from boilers and coal handling from APEN submitted 4/30/08 (2007 data)
Actual emissions from the sodium reagent silos from APEN submitted 4/9/07 (2006 data)
Actual emissions from the cooling towers are from the APENs submitted 4/19/05 and 9/21/05 (2004 data)
Actual emissions from ash handling (silo) and haul roads are based on APEN submitted 4/27/04 (2003 data)
HAP emissions from the boilers are HCl and HF
HAP emissions from the cooling towers are chloroform